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Regional Haze
Four-Factor Analysis

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INTERNATIONAL PAPER
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SECTION 1
INTRODUCTION

On 2 July 1999 the United States Environmental Protection Agency (USEPA) issued the Regional Haze rule regulations. The Regional Haze rule is intended to improve visibility in 156 national parks and wilderness areas across the country. Under the Regional Haze Rule, the Georgia Environmental Protection Division (EPD) must submit a State Implementation Plan (SIP) to demonstrate reasonable progress in achieving natural visibility conditions.

EPD has identified the No. 13 Power Boiler at the International Paper Savannah Mill as likely to contribute more than 0.5% to the total visibility impairment caused by sulfate at the Wolf Island National Wildlife Refuge and Okefenokee Wilderness Areas in Georgia. Therefore, EPD has requested that International Paper evaluate the feasibility of installing SO_2 emission controls for the No. 13 Power Boiler. This analysis requires consideration of four statutory factors:

- Cost of compliance
- Time necessary for compliance
- Energy and non-air quality environmental impacts of compliance
- Remaining useful life of the source

SECTION 2
BACKGROUND

The Savannah Mill is located in Chatham County, Georgia, across the Savannah River from South Carolina. It occupies a 450-acre site, and produces unbleached kraft linerboard, corrugating medium, and saturating kraft paper. The Savannah Mill currently operates three paper machines, with one machine dedicated to making saturating kraft. The mill was upgraded in 1991, adding a new wood chipping line, Kamyr digester, lime kiln, and a new high speed linerboard/paper machine. The mill currently employs approximately 650 persons.

The No. 13 Power Boiler at Savannah is a Combustion Engineering unit with a maximum firing rate of up to 1,280 MMBtu/hour. The boiler is the primary source of process steam for the pulp and papermaking operations. In addition, steam from the boiler is used to drive a steam turbine, generating power for use at the mill. The boiler is equipped with an electrostatic precipitator (ESP) for controlling particulate emissions from the boiler.

The No. 13 Power Boiler burns primarily coal at up to 1.2 lb/MMBtu SO_2. Distillate oil is used only for the igniters. Bark and wood fines are also fired.

In addition, the boiler is used to control emissions from the pulping process as required by regulation and permit. These gases contribute approximately 35% of the total sulfur load to the boiler. These waste gas streams include low-volume high-concentration (LVHC) non-condensable gases (NCG), high-volume low-concentration (HVLC) NCG, and stripper off-gases (SOG).

Boiler service life is estimated to be at least 40 years from installation, or until approximately 2022 or later.

SECTION 3
IDENTIFICATION OF POTENTIAL CONTROL OPTIONS

The methodology used in this analysis for evaluation of potential SO_2 emission controls for the No. 13 Power Boiler follows the "top-down" approach requested by EPD. The "top-down" approach contains the following elements:

- Identification of potentially available control alternatives.
- Identification and ranking of feasible control alternatives.
- Assessment of cost, energy, and other non-air quality environmental impacts of compliance for technically feasible alternatives.
- Selection of the control alternative.

Appendix C includes a review of the RACT/BACT/LAER Clearinghouse (RBLC) for coal and biomass fired boilers >250 MMBtu/. The types of emission control methods utilized by boilers listed in the RBLC include (RBLC terminology): Wet Flue Gas Desulphurization (FGD) Scrubber, Absorber/Spray Dryer, Dryer Sorbent Injection, Low Sulfur Fuels, None.

The following potential control devices were identified for controlling SO_2 emissions from the No. 13 Power Boiler:

- wet caustic packed scrubber (a version of FGD)
- wet limestone spray tower (a version of FGD)
- Semi-dry lime spray dryer
- Dry Sorbent Injection
- Low Sulfur Fuels

<u>**WET SCRUBBING METHODS:**</u> With wet FGD scrubbing, flue gas is contacted with a slurry of water and lime (CaO), limestone ($CaCO_3$), or a caustic ($NaOH$) solution. SO_2 reacts with the lime or limestone to form solid calcium sulfite or calcium sulfate salts which remain suspended in the water slurry. Caustic scrubbing yields primarily soluble sodium sulfite/sodium sulfate; however, calcium from the water and the fuels also leads to formation of calcium sulfite/sulfate scale and suspended solids. Wet scrubbing produces large quantities of liquid effluent and (when lime or limestone are used) calcium sulfite/sulfate sludge. Wet FGD scrubbing can achieve 90 to 95% SO_2 removal. Typically, an FGD scrubber is located downstream of a particulate control device. The No. 13 Power Boiler has an existing ESP for particulate control.

For this evaluation, both a wet caustic packed tower scrubber and a wet limestone spray tower were evaluated. Both technologies have been demonstrated and are considered to be technically feasible options for controlling SO_2 emissions from the No. 13 Power Boiler. The reduced operating temperature would require either reheat or stack and ductwork replacement downstream of the new scrubber for acid resistance. In this case, the cost of reheating the flue gas was incorporated due to the size of the existing stack.

SEMI-DRY SCRUBBING: With a semi-dry spray dryer, lime or sodium based alkaline slurry is injected into the flue gas in a spray dryer vessel forming small droplets. The droplets absorb SO_2 emissions from the flue gas and ultimately become sulfate particulates upon evaporation of the water. The particles are then collected in a particulate control device. Semi-dry spray dryers can achieve an SO_2 removal rate of up to 85%. The No. 13 Power Boiler at the International Paper facility already has an ESP for particulate control, but it would not be adequate for the additional particulate load. Additionally, the reduced operating temperature would require either reheat or replacement of the ESP, ductwork and stack downstream of the spray dryer due to condensation of sulfuric acid. In this case, the cost of reheating the flue gas was incorporated due to the size of the existing stack. Semi-dry lime spray dryer technology has been demonstrated and is considered to be technically feasible under the above conditions for controlling SO_2 emissions from the No. 13 Power Boiler.

DRY SCRUBBING/DRY SORBENT INJECTION: Similar to the semi-dry process, dry sorbent injection involves injecting dry powdered lime or other suitable sorbent directly into the flue gas. However, a spray dryer is not required for the dry injection process. The SO_2 emissions react directly with the dry particles to form sulfate particulates. The particulates are then collected in a particulate control device. Dry sorbent injection technology can achieve 20 to 50% SO_2 removal, and some vendors claim higher values. Dry sorbent injection technology has been demonstrated and is considered to be technically feasible for controlling SO_2 emissions from the No. 13 Power Boiler. The ESP would have to be upgraded to handle the additional particulate load. Various reagents, injection locations/temperature regimes and claimed efficiencies are referenced in technical and commercial literature. Due to concerns about equipment erosion and conservatism about vendor claims, the lower end of claimed efficiencies has been selected for this option.

LOW SULFUR FUELS: The final option considered for controlling SO_2 emissions from the No. 13 Power Boiler is conversion to low sulfur fuels. Three low sulfur fuel types have been considered – natural gas, distillate oil, and wood products. As previously noted, only about 65% of the sulfur to the boiler is from sulfur contained in the fuels. The remaining 35% of the sulfur comes from pulping off-gases that are processed in the boiler. Therefore, conversion to low sulfur fuels would reduce SO_2 emissions by less than 65%.

The fuels currently used by the boiler are primarily coal, wood products (primarily bark), and a small amount of distillate oil used for igniters.

Natural gas would be considered as the cleanest of the fuel alternatives, having minimal sulfur content. Natural gas is considered to be technically feasible for reducing SO_2 emissions from the No. 13 Power

Boiler, but would require a new fuel delivery system to the boiler, new burners and fuel handling modifications to the mill site.

Conversion to distillate oil is feasible for reducing SO_2 emissions from the No. 13 Power Boiler, but would require a new fuel delivery system to the boiler, new burners, and additional fuel storage and handling modifications to the mill site.

Savannah Mill staff has found that increased bark firing results in furnace erosion, fireside tube pluggage, and reduced boiler efficiency. Thus, full conversion to wood firing is not considered technically feasible. Even if these factors were not limiting, a major boiler and mill-site modification would be required to install a traveling grate for boiler operation with total wood combustion. It would also be necessary to extensively modify the fuel delivery and storage systems.

Ranking of Control Options

The options evaluated for reducing SO_2 emissions from the No. 13 Power Boiler are ranked, in order of potential removal efficiency as:

1. Wet Scrubbing, Caustic Packed Scrubber – 95% reduction
2. Wet Scrubbing, Limestone Spray Tower – 90% reduction
3. Semi-dry Scrubbing, Lime Spray Dryer – 85% reduction
4. Conversion to Low Sulfur Fuels – <65%
5. Dry Scrubbing, Dry Sorbent Injection – 25%

SECTION 4
EVALUATION OF CONTROL OPTIONS

Table 4-1 presents summary information on all options evaluated for this study. The CUECost model (see below) is a complex EPA spreadsheet. To avoid unintended consequences, certain costs were computed separately. See text in each technology section below. Table 4-1 contains results developed using CUECost only for the caustic packed scrubber, the limestone spray tower, the lime spray dryer and dry sorbent injection. For the dry sorbent injection alternative, the costs associated with lost production had a significant impact on the final cost effectiveness values, and a separate computation was done. For the low sulfur fuel alternatives, developed using other methods, it was practical to incorporate the costs into the existing cost-effectiveness result. See "Other Impacts" sections for each technology where additional costs are not included in Table 4-1.

TABLE 4-1
SUMMARY OF SO_2 CONTROL COSTS AND IMPACTS

Control Method	TCI, \$	Annualized Cost, \$	Control Efficiency, %	\$ / Ton Controlled	Tons Controlled	Electric Power Consumed, kWh/yr	Water Consumed, M gal/yr	Waste Water Generated, M gal/yr	Solid Waste Generated, tons/yr	Energy (heat) Consumed, MMBtu/yr [b]
Packed Tower	139,041,065	39,905,025	95%	\$4,900	8,149	19,425,545	211,688	161,036		1,400,332
Spray Tower	92,378,864	33,868,334	90%	\$4,126	7.720	19,425,545	0	0	22,043	1,308,923
Spray Dry Scrubber	70,669,228	35,469,650	85%	\$4,947	7,291	6,798,941	113,824		19,269	1,308,923
Fuel Switching--Natural Gas [a]	24,000,000	52,969,669	65%	\$9,500	5,576					
Fuel Switching--Distillate Oil [a]	26,000,000	121,752,814	41% [c]	\$34,927	3,486					
Dry Sorbent Injection	22,059,810	6,322,889	25%	\$2,950	2,144	2,453,753			7,850	
Dry Sorbent Injection [a]	64,059,810	11,229,730	25%	\$5,200	2,144	2,453,753			7,850	

[a] Capital and annualized costs include cost of lost production.
[b] Approximately the same amount of stack gas reheat was estimated for the wet and semi-dry technologies.
[c] AP-42 factor for 0.5% S distillate oil.

Caustic Packed Scrubber

Costs of Compliance

Costs associated with installation of a caustic packed scrubber for controlling SO_2 emissions from the No. 13 Power Boiler were estimated utilizing the Coal Utility Environmental Cost (CUECost) software tool. The CUECost software is a series of spreadsheets that was developed under contract for the U.S. EPA and is stated to provide +/- 30% cost estimates of the installed capital and annualized operating costs for air pollution control (APC) systems installed on coal-fired power plants to control emissions of sulfur dioxide, nitrogen oxides (NOx), and particulate matter. Appendix A contains a narrative on the CUECost model and the specific references and methods used for this evaluation.

The Savannah No. 13 Power Boiler is a large industrial boiler, rated for approximately 1280 MMBtu/hr heat input. While power boilers in the pulp and paper industry have different fuel mixtures, operating regimes (i.e., rapid load swings) and space constraints than utility boilers, the No. 13 Power Boiler could produce in excess of 100 MW of electricity if it were used as a utility boiler. On the basis of size alone, the CUECost model is considered reasonable for SO_2 and particulate control requirements for the No. 13 Power Boiler at International Paper Savannah Mill.

The CUECost model was first used to develop the capital cost estimates for a limestone spray tower system. These capital costs were used after subtraction of the capital costs associated with the limestone reagent system to estimate the capital costs for a caustic packed scrubber. The site is severely constrained and thus a 1.6 retrofit difficulty factor was applied instead of the standard 1.3 factor for retrofit. Annualized costs were estimated based on the estimated capital costs and based on the standardized procedures and algorithms from the Sixth Edition of the OAQPS Control Cost Manual (U.S. EPA, EPA 452/B-02-001). A 15-year project life and 8% cost of capital were assumed.

Based on the cost estimates developed, the total capital investment that would be required for a caustic packed scrubber to reduce SO_2 emissions by 95% from the No. 13 Power Boiler is approximately \$139,041,000. The annualized operating costs for operating a caustic packed scrubber are approximately \$39,905,000. Appendix B, Table B-1 and Table B-2 provide detailed information on the cost estimates for capital and operating costs, respectively, for the packed tower option as determined by the CUECost model and the Control Cost Manual. Table B-2A shows additional calculations for cost of lost production and wastewater treatment upgrades. Details are presented in "Other Impacts." These additional costs are not included in Table 4-1.

Uncontrolled SO_2 emissions for 2018 are estimated at approximately 8,578 tons per year. Based on a removal efficiency of 95%, this would result in a reduction of approximately 8,149 tons per year. The overall cost effectiveness for utilizing a caustic packed scrubber for reducing SO_2 emissions from the No. 13 Power Boiler is approximately \$4,900 per ton of SO_2 removed. This figure does not include cost impacts of lost production or wastewater treatment upgrades.

Time for Compliance

International Paper anticipates that it would take until at least 2010 to 2012 to incorporate these costs into the capital and operating budgets for the International Paper Savannah Mill, complete detailed design and engineering, and construct the scrubber.

Other Impacts

In addition to the capital and operating costs, a caustic packed scrubber would have other impacts on the International Paper mill operations. These additional impacts include:

- Additional energy would be expended to operate the pumps and larger exhaust fan associated with a packed scrubber. This would result in an additional electrical energy usage of approximately 19,425 MWH of electricity per year. The costs associated with the energy usage were included in the annualized cost estimates.

- The stack gas would need to be reheated to raise the temperature to above the dew point of sulfuric acid. This would require use of an additional 1,400,000 MMBtu per year of energy. The costs associated with reheating the stack gas were included in the annualized cost estimates.

- A packed scrubber would use over 211 million gallons of water per year. Water usage costs have been considered in the estimate.

- A packed scrubber would generate an additional 161 million gallons of wastewater per year. This wastewater would need to be treated at the mill's current wastewater treatment plant. The Chemical Oxygen Demand (COD) from sulfite oxidation would require additional aeration at a minimum. Power for additional aeration is not currently available at the waste treatment site. In addition, pending reduced effluent limits at the mill due to implementation of Total Maximum Daily Loads (TMDLs) in the Savannah Harbor will further limit the facility's ability to treat additional wastewater load. Therefore, treatment of this wastewater would require additional capital costs and energy usage for the mill. An assumed $2- million capital cost has been proposed to permit treatment pond expansion, flow optimization, additional aeration or addition of an oxygen diffusion system, with annual operating expenses of $200,000 for maintenance, energy and oxygen supply. With a 15-year project life and 8% cost of capital, these factors add $433,659 to the annual operating cost of the scrubber. These costs are in addition to the values from the CUECost model presented in Tables B-1 and B-2, and are not reflected in Table 4-1. Calculations are shown in Table B-2A.

- The installation of a caustic scrubber would require an estimated two additional weeks beyond the normal scheduled outage time of No. 13 Power Boiler for installation. The downtime estimate includes time for system testing and shakedown prior to start of routine operations. During downtime of the boiler, mill operations would have to be reduced by at least 50 percent. The cost to the mill for this reduction in productivity is estimated at approximately $3,000,000 per day, or a total cost of approximately $42,000,000. Because the CUECost model is such a complex worksheet, these costs have been computed separately. See "Other Impacts" section and Table B-2A. With a 15-year project life and 8% cost of capital, this adds $4,906,841 to the annual operating cost of the scrubber. These costs are in addition to the values from the CUECost model presented in Tables B-1 and B-2, and are not reflected in Table 4-1. Calculations are shown in Table B-2A.

Limestone Spray Tower

Costs of Compliance

Costs associated with installation of a limestone spray tower for controlling SO_2 emissions from the No. 13 Power Boiler were estimated utilizing the CUECost software tool. Based on the cost estimates developed, the total capital investment that would be required for a limestone spray tower to reduce SO_2 emissions by 90% from the No. 13 Power Boiler is approximately $92,379,000. The annualized, first year operating costs for operating a limestone spray tower are approximately $33,868,000. Table B-3 in Appendix B provides output data from the CUECost software tool on the cost estimates.

Uncontrolled SO_2 emissions for 2018 are estimated at approximately 8,578 tons per year. Based on a removal efficiency of 90%, this would result in a reduction of approximately 7,720 tons per year. The overall cost effectiveness for utilizing a limestone spray tower for reducing SO_2 emissions from the No. 13 Power Boiler is approximately $4,126 (levelized current) per ton of SO_2 removed. This figure does not include cost impacts of lost production or wastewater treatment upgrades. See "Other Impacts."

Time for Compliance

International Paper anticipates that it would take until at least 2010 to 2012 to incorporate these costs into the capital and operating budgets for the International Paper Savannah Mill, complete detailed design and engineering, and construct the spray tower.

Other Impacts

In addition to the capital and operating costs, a limestone spray tower scrubber would have other impacts on the International Paper mill operations. These additional impacts include:

- Additional energy would be expended to operate the pumps and exhaust fan associated with a limestone spray tower. This would result in an additional energy usage of approximately 19,425 MWH of electricity per year. The costs associated with the energy usage were included in the annualized cost estimates.

- The stack gas would need to be reheated to raise the temperature to above the dew point of sulfuric acid. This would require use of an additional 1,309,000 MMBtu per year of energy. The costs associated with reheating the stack gas were included in the annualized cost estimates.

- A limestone spray tower would use over 71 million gallons of water per year. Water usage costs have been considered in the estimate.

- A limestone spray tower would generate an additional 22 million gallons of wastewater per year. This wastewater would need to be treated at the mill's current wastewater treatment plant. Pending reduced effluent limits at the mill due to implementation of TMDLs in the Savannah Harbor will greatly limit the facility's ability to treat additional wastewater load. Therefore, treatment of this wastewater would require additional capital costs and energy usage for the mill. An assumed $2 million capital cost has been proposed to permit treatment pond expansion, flow optimization, additional aeration or addition of an oxygen diffusion system, with annual operating expenses of $200,000 for maintenance, energy and oxygen supply. With a 15-year project life and 8% cost of capital, these factors add $433,659 to the annual operating cost of the scrubber. Because the CUECost model is such a complex worksheet, these costs have been computed separately. See "Other Impacts" section and Table B-3A. These costs are in addition to the values from the CUECost model presented in Tables B-3 and are not reflected in Table 4-1.

- An additional 22,000 tons per year of calcium sludge would be generated from the SO_2 scrubbing.

- Increased truck and/or train traffic to bring limestone to the mill and remove increased amounts of sludge from the wastewater operations at the mill.

- The installation of a limestone spray tower would require an estimated two additional weeks beyond the normal scheduled outage time of No. 13 Power Boiler for installation. The downtime estimate includes time for system testing and shakedown prior to the start of routine operations. During downtime of the boiler, mill operations would have to be reduced by at least 50 percent. The cost to the mill for this reduction in productivity is estimated at approximately $3,000,000 per day, or a total cost of approximately $42,000,000. Because the CUECost model is such a complex worksheet, these costs have been computed separately. See "Other Impacts" section and Table B-3A. With a 15-year project life and 8% cost of capital, this adds $4,906,841 to the annual operating cost of the scrubber. These costs are in addition to the values from the CUECost model presented in Table B-3, and are not reflected in Table 4-1. Calculations are shown in Table B-3A.

Lime Spray Dryer

Costs of Compliance

Costs associated with installing a lime spray dryer for controlling SO_2 emissions from the No. 13 Power Boiler were estimated utilizing the CUECost software tool. Based on the cost estimates developed, the total capital investment that would be required for a lime spray tower to reduce SO_2 emissions by 85% from the No. 13 Power Boiler is approximately $70,669,228, including the additional ESP capacity required. The first year annualized operating costs for operating a lime spray dryer are approximately $35,470,000. Table B-4 in Appendix B provides output data from the CUECost software tool on the cost estimates.

Uncontrolled SO_2 emissions for 2018 are estimated at approximately 8,578 tons per year. Based on a removal efficiency of 85%, this would result in a reduction of approximately 7,291 tons per year. The overall cost effectiveness for utilizing a lime spray dryer for reducing SO_2 emissions from the No. 13 Power Boiler is approximately $4,947 (levelized current) per ton of SO_2 removed. This figure does not include cost impacts of lost production or wastewater treatment upgrades.

Time for Compliance

International Paper anticipates that it would take until at least 2010 to 2012 to incorporate these costs into the capital and operating budgets for the International Paper Savannah Mill, complete detailed design and engineering, and construct the required equipment.

Other Impacts

In addition to the capital and operating costs, a lime spray dryer would have other impacts on the International Paper mill operations, including:

- Additional energy would be expended to operate the pumps and exhaust fan associated with a lime slurry formation and injection system and the spray dryer operations. This would result in an additional energy usage of approximately 6,799 MWH of electricity per year. The costs associated with the energy usage were included in the annualized cost estimates.
- The stack gas would need to be reheated to raise the temperature to above the dew point of sulfuric acid. This would require the use of an additional 1,309,000 MMBtu per year of energy. The costs associated with reheating the stack gas were included in the annualized cost estimates.
- A lime spray dryer would use over 114 million gallons of water per year. Water usage costs have been considered in the estimate.

- The lime spray dryer would generate an additional 19,000 tons per year of flyash/particulate matter collected in the ESP. This would result in additional waste materials being generated from the facility and sent to landfill for disposal.

- Increased truck and/or train traffic to bring lime to the mill and remove increased amounts of flyash/particulate matter from the operations at the mill.

- The installation of lime spray dryer system would require an estimated four additional weeks beyond the normal scheduled outage time of No. 13 Power Boiler for installation. The downtime estimate includes time for system testing and shakedown prior to start of routine operations. During downtime of the boiler, mill operations would have to be reduced by at least 50 percent. The cost to the mill for this reduction in productivity is estimated at approximately $3,000,000 per day, or a total cost of approximately $84,000,000. Because the CUECost model is such a complex worksheet, these costs have been computed separately. See "Other Impacts" section and Table B-4A. With a 15-year project life and 8% cost of capital, this adds $9,813,682 to the annual operating cost of the scrubber. These costs are in addition to the values from the CUECost model presented in Table B-4, and are not reflected in Table 4-1. Calculations are shown in Table B-4A.

Low Sulfur Fuels

Costs of Compliance

Three low sulfur fuels have been considered for lowering SO_2 emissions from No. 13 Power Boiler – natural gas, distillate oil, and wood products.

Natural Gas: The boiler currently does not fire natural gas; however, natural gas is used for other sources at the mill. To utilize natural gas in the boiler, an extension of the gas line to the boiler would need to be installed and natural gas burners would need to be installed in the boiler.

Capital and fuel costs were obtained from International Paper Technology estimates based on similar projects at other facilities. The total capital investment that would be required for converting to natural gas to reduce SO_2 emissions by 65% from the No. 13 Power Boiler is approximately $3,000,000, plus $21,000,000 for lost production costs. The annualized operating costs for converting to natural gas are approximately $52,970,000. Table B-5 in Appendix B provides additional details on the cost estimates.

Uncontrolled SO_2 emissions for 2018 are estimated at approximately 8,578 tons per year. Based on a reduction of 65%, this would result in a reduction of approximately 5,576 tons per year. The overall cost effectiveness for converting to natural gas to reduce SO_2 emissions from the No. 13 Power Boiler is approximately $ 9,500 per ton of SO_2 removed. This figure does include cost impacts of lost production or wastewater treatment upgrades.

Distillate Oil: The No. 13 Power Boiler utilizes distillate oil for igniters only, not load. To use distillate oil for steam generation, new burners, a new fuel delivery system and oil storage tank would be required. To operate at boiler capacity of 1280 MMBtu/hr, a greater than three million gallon storage tank would be necessary to provide a minimally adequate 15-day inventory. Additionally, 31 tanker trucks per day would be required to deliver the fuel. Existing dock and rail facilities are not adequate for barge or train delivery, respectively.

Capital costs for tankage and piping were developed from fuels experience for Weston Solutions projects. Fuel cost was obtained from DOE website for industrial distillate oil purchases. The total capital investment that would be required for conversion to distillate oil to reduce SO_2 emissions from the No. 13 Power Boiler is approximately \$5,000,000, plus \$21,000,000 for lost production costs. The annualized operating costs for converting to distillate oil are approximately \$121,753,000. The AP-42 factor for 0.5% sulfur distillate oil was used to project an annual reduction of 3,486 tons of SO_2. The overall cost effectiveness for converting to distillate oil to reduce SO_2 emissions from the No. 13 Power Boiler is approximately \$34,927 per ton of SO_2 removed. This figure does include cost impacts of lost production or wastewater treatment upgrades. Table B-6 in Appendix B provides additional details on the cost estimates.

Wood Products: Savannah mill staff have found that furnace erosion, fireside tube pluggage and reduced boiler efficiency result from increased bark firing. Thus full conversion to wood firing is not considered technically feasible.

Even if these factors were not limiting, a major boiler and mill-site modification would be required to install a traveling grate for boiler operation with total wood combustion. It would also be necessary to extensively modify the fuel delivery and storage systems. An item from BART requirements suggests such a modification may not be reasonable: 40 CFR 51, Appendix Y, IV.D.5, p. 564: 5. We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis.

Time for Compliance

The capital costs associated with conversion to either natural gas or to distillate oil firing are relatively low compared to the costs associated with the other options evaluated. However, the annual operating costs associated with conversion to a low sulfur fuel are extremely significant, due to the higher fuel costs. International Paper anticipates that it would take until at least 2010 to 2012 to incorporate these costs into the capital and operating budgets for the International Paper Savannah Mill, complete detailed design and engineering, and install the required equipment.

Other Impacts

In addition to the capital and operating costs, conversion to low sulfur fuels would have other impacts on the International Paper mill operations. These additional impacts include:

- Installation of natural gas or oil burners would require an estimated one additional week beyond the normal scheduled outage time of No. 13 Power Boiler for installation. The downtime estimate includes time for system testing and shakedown prior to start of routine operations. During downtime of the boiler, mill operations would have to be reduced by at least 50 percent. The cost to the mill for this reduction in productivity is estimated at approximately $3,000,000 per day, or a total cost of approximately $21,000,000. These costs are included in Table 4-1 (summary) and Tables B-5 and B-6.

- Conversion to oil would require the installation of a large oil storage tank. This tank would require secondary containment along with other environmental and safety monitoring systems. In addition, this tank would require incorporation into the mill's Spill Prevention, Control and Countermeasures (SPCC) Plan.

- Receiving distillate oil via trucks would impose additional environmental and safety requirements at the mill and create traffic, personnel and material flow problems.

Dry Sorbent Injection

Costs of Compliance

Costs associated with application of dry sorbent injection for controlling SO_2 emissions from the No. 13 Power Boiler were estimated utilizing literature information for equipment costs and EPA Control Cost Manual methodologies for estimating total capital investment and annual costs. As discussed in Appendix A, the Control Cost Manual does not cover dry sorbent injection for SO_2 control but does contain cost estimating methodologies for an analogous NO_X control technology called selective noncatalytic reduction (SNCR). Based on the cost estimates developed, the total capital investment that would be required for a dry sorbent injection system to reduce SO_2 emissions by 25% from the No. 13 Power Boiler is approximately $22,059,810, including the required additional ESP capacity. The annualized operating costs for operating a dry sorbent injection system are approximately $6,322,889. Note: These costs do not include the capital or annualized costs due to lost production. These costs have been computed separately--see "Other Impacts" section and Table B-8A. Table B-7 and B-8 in Appendix B provide detailed information on the cost estimates for other capital and operating costs, respectively, for the dry sorbent injection option.

Uncontrolled SO_2 emissions for 2018 are estimated at approximately 8,578 tons per year. Based on a removal efficiency of 25%, this would result in a reduction of approximately 2,144 tons per year.

The overall cost effectiveness for utilizing a dry sorbent injection system for reducing SO_2 emissions from the No. 13 Power Boiler is approximately $2,950 per ton of SO_2 removed. Considering the cost impact of lost production, the cost effectiveness would be $5,200/ton.

Time for Compliance

International Paper anticipates that it would take until at least 2010 to 2012 to incorporate these costs into the capital and operating budgets for the International Paper Savannah Mill, complete detailed design and engineering, and install the required equipment.

Other Impacts

In addition to the capital and operating costs, a dry sorbent injection system would have other impacts on the International Paper mill operations. These additional impacts include:

- Additional energy would be expended to operate the compressors with a sorbent injection system. This would result in an additional energy usage of approximately 2,454 MWH of electricity per year. The costs associated with the energy usage were included in the annualized cost estimates.
- The dry sorbent injection system would create an additional 7,850 tons per year of flyash/particulate matter collected in the ESP. This would result in additional waste materials being generated from the facility and sent to landfill for disposal.
- Increased truck and/or train traffic to bring sorbent to the mill and remove increased amounts of flyash/particulate matter from the operations at the mill.
- The installation of dry sorbent injection system would require an estimated two additional weeks beyond the normal scheduled outage time of the No. 13 Power Boiler for installation. The downtime estimate includes time for system testing and shakedown prior to start of routine operations. During downtime of the boiler, mill operations would have to be reduced by at least 50 percent. The cost to the mill for this reduction in productivity is estimated at approximately $3,000,000 per day, or a total cost of approximately $42,000,000. With a 15-year project life and 8% cost of capital, this adds $4,906,841 to the annual operating cost of the scrubber. These costs are in addition to the values presented in Tables B-7 and B-8, and are reflected in the last line of Table 4-1. Calculations are shown in Table B-8A.

SECTION 5
SELECTION OF TECHNOLOGY

EPD has requested that the International Paper Savannah mill evaluate the feasibility of control technologies for controlling SO_2 emissions from the No. 13 Power Boiler at the mill. International Paper has evaluated and determined the following control options to be technically feasible, listed in order by potential control efficiency:

1. Caustic Packed Scrubber – 95% reduction
2. Limestone Spray Tower – 90% reduction
3. Lime Spray Dryer – 85% reduction
4. Conversion to Low Sulfur Fuels (natural gas or distillate oil) – <65%
5. Dry Sorbent Injection – 25%

Conversion to wood firing was deemed technically infeasible due to problems with furnace erosion, fireside tube pluggage, and reduced operating efficiency.

The feasible options were evaluated for the associated costs, time to implement, and other impacts associated with implementing the control options. Table 4-1 provides a summary of the evaluation. The CUECost model is a complex EPA spreadsheet. To avoid unintended consequences, certain costs were computed separately. See text in each technology section. Table 4-1 contains CUECost results for the caustic packed scrubber, the limestone spray tower, the lime spray dryer and dry sorbent injection. For the dry sorbent injection alternative, the costs associated with lost production had a significant impact on the final cost effectiveness values, and a separate computation was done. For the low sulfur fuel alternatives, it was practical to incorporate the costs into the existing cost-effectiveness result. See "Other Impacts" sections for each technology where additional costs are not included in Table 4-1.

Based on this analysis, International Paper has concluded that none of the feasible control options are economically reasonable to implement for the No. 13 Power Boiler. The associated capital and/or operating costs are unreasonably high and would place too high of an economic burden on the mill. These costs would result in great economic strain on the mill operations and potentially jeopardize the ability for International Paper to profitably operate the mill, thus jeopardizing the future operations of the facility.

In addition, the evaluated options would present additional impacts on the facility, including:

- Addition of a packed scrubber or spray tower would generate a significant amount of wastewater, which the current wastewater treatment system cannot handle without significant upgrades.
- The increased sulfur load and chemical oxygen demand for the packed tower caustic scrubber discharge to the wastewater treatment system would increase the possibility of odor generation. There is currently inadequate power to add aeration capacity to wastewater treatment.
- A packed scrubber, spray tower or spray dryer would significantly increase the water usage for the mill. Increased water use could only come from the city Industrial and Domestic facility, as there is no ability to increase groundwater withdrawals. City water costs \$675 to \$856/million gallons; however the ability for the city to supply the required quantity has not been determined.
- A spray tower, spray dryer or dry sorbent injection system would greatly increase the volume of solid waste generated from the mill that would ultimately be landfilled. In addition, truck and/or rail traffic in and out of the mill would significantly increase for delivery of reagent and transfer of waste materials.
- Conversion to distillate oil would place additional regulatory requirements on the mill and require additional manpower and costs for monitoring and maintaining the systems to prevent potential oil leaks and spills. In addition, truck traffic in and out of the mill would significantly increase for delivery of fuel oil.
- All of the options would require significant downtime of the boiler to implement. The facility does not have adequate backup steam supply to replace the boiler during such downtime. Therefore, the facility would incur significant losses in productivity from the boiler downtime, resulting in significant negative economic impacts on the mill's operations.

Therefore, International Paper believes that none of the evaluated options are economically feasible for reducing SO_2 emissions from the No. 13 Power Boiler.

Appendix A
CUECost Model Specific References and Methods Used

AIR POLLUTION CONTROL DEVICE COST METHODOLOGY

To prepare the air pollution control device costs in the following tables, several sources of information were relied upon as instructed by EPA in 40 CFR 51.308 and Appendix Y thereto. Among the sources of information examined were the following:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database (http://cfpub.epa.gov/rblc/htm/bl02.cfm)
- EPA's Clean Air Technology Center products and tools (http://www.epa.gov/ttn/catc/)
- EPA's OAQPS 'Air Pollution Control Cost Manual', 6th Edition, EPA/452/B-02-001, January 2002
- EPA fact sheets and technical assessment documents on flue gas desulphurization (FGD) technologies for SO_2 control
- DOE technology reports for control of SO_2
- VISTA and MANE-VU state organization internet web pages
- IEA Clean Coal Center web page (http://www.coalonline.info/site/coalonline/)

The main source for wet scrubber and spray dry scrubber cost estimates was the Coal Utility Environmental Cost (CUECost) workbook, an interrelated set of spreadsheets developed by Raytheon Engineers & Constructors, Inc. for EPA in 1998 and revised in 2000. The CUECost workbook produces rough-order-of-magnitude (ROM) cost estimates (+/-30% accuracy) of the installed capital and annualized operating costs for air pollution control (APC) systems installed on coal-fired power plants to control emissions of sulfur dioxide and other pollutants. The APC technologies addressed by the models are:

- Flue Gas Desulphurization (FGD) = Limestone with Forced Oxidation (LSFO)
  Lime Spray Drying (LSD)
  Limestone with Dibasic Acid (LSDBA)

- Particulate Matter Removal = Electrostatic Precipitator (ESP)
  Fabric Filter (FF)

- Nitrogen Oxide Control = Selective Catalytic Reduction (SCR)
  Selective Non-Catalytic Reduction (SNCR)
  Natural Gas Reburning (NGR)
  Low NO_x Burners (LNB)

heater. For duct sorbent injection, reaction kinetics are typically less robust because of less favorable residence time, temperature, and mixing considerations.

Limited literature data on equipment costs for DSI systems was discovered. To estimate cost parameters based upon the Air Pollution Control Cost Manual, data for selective noncatalytic reduction (SNCR) for NO_X control was adapted to DSI because of the similarities between the two. Both methods inject reagent into the combustion gas to react with the targeted pollutant and require similar, relatively limited and inexpensive equipment. Also, many of the annual costs are comparable.

Cost tables printed from the CUECost model for LFSO and LSD technologies are included herein. Also included are the cost tables for PT and DSI in the format used by EPA's OAQPS 'Air Pollution Control Cost Manual'.

Appendix B
Air Pollution Control Device Cost Details

TABLE B-1
IP SAVANNAH MILL PACKED SCRUBBER
SO2 PACKED SCRUBBER TCI ESTIMATE

COST ITEM	FACTOR[a]		
Direct Capital Costs			
Purchased equipment costs			
Packed Tower Scrubber System		= $	-
Ductwork		= $	-
Equipment Cost	A	= $	-
Instrumentation	0.10 A	= $	-
Sales taxes	0.03 A	= $	-
Freight	0.05 A	= $	-
Purchased equipment cost, PEC	B = 1.18 A	= $	-
Direct installation costs			
Foundations & supports	0.12 B	= $	-
Handling & erection	0.40 B	= $	-
Electrical	0.01 B	= $	-
Piping	0.30 B	= $	-
Insulation	0.01 B	= $	-
Painting	0.01 B	= $	-
Direct installation costs	0.85 B	= $	-
Site preparation	As required, SP	=	
Buildings	As required, Bldg.	= $	-
Total Direct Costs, DC	1.85 B + SP + Bldg.	= $	-
Indirect Costs (installation)			
Engineering	0.10 B	= $	-
Construction and field expenses	0.10 B	= $	-
Contractor fees	0.10 B	= $	-
Start-up	0.01 B	= $	-
Performance test	0.01 B	= $	-
Contingencies	0.03 B	= $	-
Total Indirect Costs, IC	0.35 B	= $	-
TCI for limestone spray tower with FO			$101,230,103
TCI component for limestone reagent system			($8,536,060)
Total before spray tower to packed multiplier			$92,694,043
Spray tower to packed tower multiplier			1.5
Total Capital Investment = DC + IC [b]	2.20 B + SP + Bldg.	= $	139,041,065

[a] From the OAQPS Control Cost Manual, Sixth Edition, January 2002. Document number EPA 452/B-02-001. However, since documented equipment costs were not readily available, packed tower TCI is based on spray tower TCI minus the limestone reagent system TCI component as noted below.

[b] TCI provided in EPA Coal Utility spreadsheet for a spray tower scrubber scaled by a conservatively low factor of 1.5 per EPA Fact Sheet guidance that spray tower capital cost range is $2 to $6/scfm and packed tower is $11 to $55/scfm, or a ratio of 5.5 to 9 (See EPA Fact Sheets for packed towers and spray towers, EPA-452/F-03-015 &-016). The specific limestone reagent system TCI components for the spray tower were subtracted from the TCI value before deriving the packed tower TCI because limestone is a more complicated and expensive reagent system than that required for a caustic (NaOH) reagent system for a packed tower.

1.5 =multiplier for packed tower x adjusted spray tower TCI from CU LSFO model

Table B-2A
Estimate of Additional Capital and Annual Operating Costs--Packed Tower Scrubber
Associated with Additional Wastewater Treatment Volume and Outage Costs
International Paper - Savannah Mill

Capital Costs			
Pond Enlargement, Aerators or O2 Diffusion System	$	2,000,000	
Outage Costs--14 days at $3 million/day	$	42,000,000	
Total	$	44,000,000	
Annualized Costs			
Interest rate:		8%	interest
Years:		15	years
Capital recovery factors:		0.117	
Capital recovery cost, Pond Enlargement/other:	$	233,659	
Capital recovery cost, Lost Production:	$	4,906,841	
Additional operating costs, Pond Enlargement/other:	$	200,000	per year
Total annual costs:	**$**	**5,340,500**	per year

Table B-3A
Estimate of Additional Capital and Annual Operating Costs--Limestone Spray Tower Scrubber
Associated with Additional Wastewater Treatment Volume and Outage Costs
International Paper - Savannah Mill

Capital Costs				
	Pond Enlargement, Aerators or O2 Diffusion System	$	2,000,000	
	Outage Costs--14 days at $3 million/day	$	42,000,000	
	Total	$	44,000,000	
Annualized Costs				
	Interest rate:		8%	interest
	Years:		15	years
	Capital recovery factors:		0.117	
	Capital recovery cost, Pond Enlargement/other:	$	233,659	
	Capital recovery cost, Lost Production:	$	4,906,841	
	Additional operating costs, Pond Enlargement/other:	$	200,000	per year
	Total annual costs:	$	**5,340,500**	per year

Table B-4 Lime Spray Dryer Costs

Description	Units	IP Sav. R. PB13
SO2 Control Costs		LSD
Total Capital Requirement (TCR)	$	$52,872,604
	$/kW	$464
First Year Costs		
Fixed O&M	$	$2,945,075.24
	$/kW-Yr	25.83
	Mills/kWH	3.03
	$/ton SO2 removed	$403.8
Variable O&M	$	$16,765,337.40
	$/kW-Yr	147.06
	Mills/kWH	17.26
	$/ton SO2 removed	$2,298.8
Fixed Charges	$	$15,759,237.75
	$/kW-Yr	138.24
	Mills/kWH	16.23
	$/ton SO2 removed	$2,160.8
TOTAL	$	$35,469,650 Cap.
	$/kW-Yr	311.14
	Mills/kWH	36.52
	$/ton SO2 removed	$4,863
Levelized Current Dollars		
Fixed O&M	$/kW-Yr	31.64
	Mills/kWH	3.71
	$/ton SO2 removed	$494.5
Variable O&M	$/kW-Yr	180.11
	Mills/kWH	21.14
	$/ton SO2 removed	$2,815.2
Fixed Charges	$/kW-Yr	104.76
	Mills/kWH	12.30
	$/ton SO2 removed	$1,637.6
TOTAL	$/kW-Yr	316.51
	Mills/kWH	37.15
	$/ton SO2 removed	$4,947.3
Levelized Constant Dollars		
Fixed O&M	$/kW-Yr	25.83
	Mills/kWH	3.03
	$/ton SO2 removed	$403.8
Variable O&M	$/kW-Yr	147.06
	Mills/kWH	17.26
	$/ton SO2 removed	$2,298.8
Fixed Charges	$/kW-Yr	72.53
	Mills/kWH	12.09
	$/ton SO2 removed	$1,610.3
TOTAL	$/kW-Yr	245.43
	Mills/kWH	32.38
	$/ton SO2 removed	$4,312.9

Total Capital Costs for Spray Dryer (Spray Dryer + New ESP) **$70,669,228**

Table B-5
Estimate of Capital and Annual Operating Costs
Associated with Conversion of Power Boiler No. 13 to Natural Gas
International Paper - Savannah Mill

Capital Costs			
Natural gas piping	$	1,000,000	
New burners	$	2,000,000	
Outage Costs--7 days at $3 million/day	$	21,000,000	
Total	$	24,000,000	
Annualized Costs			
Interest rate:		8%	interest
Years:		15	years
Capital recovery factors:		0.117	
Capital recovery cost, Burners & Piping:	$	350,489	
Capital recovery cost, lost production:	$	2,453,420	
Natural gas costs:	$	8.00	/MMBtu
Coal costs:	$	3.40	/MMBtu
Increase fuel costs:	$	4.60	/MMBtu
Fuel Usage:			
Boiler firing rate:		1280	MMBtu/hour
Annual operating hours:		8520	hours/year
		10,905,600	MMBtu/year
Additional fuel costs:	$	50,165,760	per year
Total annual costs:	$	**52,969,669**	per year
Cost Effectiveness			
Uncontrolled emissions		8,578	tons SO2/year
Removal efficiency:		65%	from switching to natural gas
Tons SO2 removed:		5,576	
Cost effectiveness:	$	**9,500**	per tons of SO2 removed

TABLE B-7
IP SAVANNAH MILL PB13
DSI SYSTEM TCI ESTIMATE

COST ITEM		FACTOR[a]			
Direct Capital Costs					
Total Direct Capital Costs, Dec. 1998[a]				$	4,395,319
Retrofit Factor		1.6			7,032,511
Total Direct Capital Costs, Oct. 2006[b]		A	=	$	9,307,470
Indirect installation costs					
General Facilities		0.05 A	=	$	465,373
Engineering and Home Office Fees		0.10 A	=	$	930,747
Process Contingency		0.05 A	=	$	465,373
Total Indirect installation costs	B =	0.20 A	=	$	1,861,494
Project Contingency	C =	0.15 (A+B)	=	$	1,675,345
Total Plant Cost	D = A + B + C		=	$	12,844,308
Additional Capital Costs					
Allowance for Funds During Construction		E[c]	=	$	-
Royalty Allowance		F[c]	=	$	-
Preproduction Cost	G =	0.02 (D+E)	=	$	256,886
Inventory Capital[d]	H =	$Vol_{reagent}$ x $Cost_{reagent}$	=	$	60,304
Initial Catalyst and Chemicals	I[c]		=	$	-
Total Additional Capital Costs			=	$	317,190
Total Capital Investment = D+E+F+G+H+I			=	$	13,161,498

[a] Average of 2 capital equipment cost estimates found from 1) IEA Clean Coal Center 1998 study and 2) DOE 1998 study, Doc. No. DE-FC22-87PC79796.

[b] Using Chemical Engineering Plant Cost Index for adjustment to current $.

[c] Assumed for SCR by EPA Control Cost Manual. Not applicable for SNCR or DSI.

[d] Assuming 14 day supply of 46% urea solution at bulk cost + tank cost

Table B-8A
Estimate of Additional Capital and Annual Operating Costs--Dry Lime Injection
Associated with Additional Outage Costs
International Paper - Savannah Mill

Capital Costs			
Outage Costs--14 days at $3 million/day	$	42,000,000	
Total	$	42,000,000	
Annualized Costs			
Interest rate:		8%	interest
Years:		15	years
Capital recovery factors:		0.117	
Capital recovery cost, Lost Production:	$	4,906,841	per year
Other Annualized Costs (Table B-8)	$	4,927,370	per year
Total annual costs:	**$**	**9,834,211**	per year
Tons Removed (Table B-8)		2145	
Annual Cost Per Ton Controlled	$	4,600	

WESTON SOLUTIONS

TA

SUMMARY OF RACT/BACT/LAER CLEARI

Rblc Id No.	Corporate or Company Name	Facility Name	Location	Permit Date	Process Name	Unit
*Al-0223	Smurfit Stone Container Corp.	Stevenson Mill	Jackson, Al	7/14/2006	No. 2 Wood-Fired Boiler	620 MM
*Mo-0050		Kansas City Power & Light Co. - Hawthorn Station	Jackson, Mo	8/17/1999	Electric Generation, Boiler, Coal	384 T/H
*Mo-0071	Great Plains Energy	Kansas City Power & Light Company - Iatan Station	Platte, Mo	1/27/2006	Pulverized Coal Boiler - Unit 2	4000 T/I
*Oh-0307	Biomass Energy	South Point Biomass Generation	Lawrence, Oh	4/4/2006	Auxiliary Boiler	227 MM
*Oh-0307	Biomass Energy	South Point Biomass Generation	Lawrence, Oh	4/4/2006	Auxiliary Boiler	247 MM
*Oh-0307	Biomass Energy	South Point Biomass Generation	Lawrence, Oh	4/4/2006	Wood Fired Boilers (7)	318 MM
*Pa-0176	Orion Power Midwest Lp	Orion Power Midwest Lp	Lawrence, Pa	4/8/1999	Boilers, Coal (3)	1029 M
*Pa-0248	Wellington Dev/Greene Energy	Greene Energy Resource Recovery Project	Greene, Pa	7/8/2005	2 Cfb Boilers	358 Tpl
*Pa-0249	River Hill Power Company, Llc	River Hill Power Company, Llc	Clearfield, Pa	7/21/2005	Auxiliary Boiler	
*Pa-0249	River Hill Power Company, Llc	River Hill Power Company, Llc	Clearfield, Pa	7/21/2005	Cfb Boiler	
*Tx-0499	Sandy Creek Energy Associates	Sandy Creek Energy Station	Mclennan,Tx	7/24/2006	Auxillary Boiler	175 MM
*Tx-0499	Sandy Creek Energy Associates	Sandy Creek Energy Station	Mclennan, Tx	7/24/2006	Plant-Emission Cap	
*Tx-0499	Sandy Creek Energy Associates	Sandy Creek Energy Station	Mclennan, Tx	7/24/2006	Pulverized Caol Boiler	8185 M
*Tx-0518	Valero Refining	Valero Heavy Oil Cracker	Nueces, Tx	11/16/2005	Emissions	
*Va-0298	International Biofuels, Inc	International Biofuels, Inc	Greensville, Va	12/13/2005	Heat Energy Systems For Pellet Processing	77 MM
*Va-0298	International Biofuels, Inc	International Biofuels, Inc	Greensville, Va	12/13/2005	Wood Thermal Oxiders For Wood Pellent Process	43 MM
*Wa-0327	Sierra Pacific Industries	Skagit County Lumber Mill	Skagit, Wa	1/25/2006	Wood-Fired Cogeneration Unit	430 M
Al-0116	Gulf States Paper Corporation	Gulf States Paper Corporation	Marengo, Al	12/10/1997	Boiler, Power	775 M
Al-0116	Gulf States Paper Corporation	Gulf States Paper Corporation	Marengo, Al	12/10/1997	Furnace, Recovery	3.94 M
Al-0116	Gulf States Paper Corporation	Gulf States Paper Corporation	Marengo, Al	12/10/1997	Smelt Dissolving Tank	3.94 M
Al-0198	Smurfit-Stone-Stevenson	Smurfit-Stone-Stevenson	Jackson, Al	9/30/2002	Boiler, No.2 Wood Residue	620 M
Ar-0074	Plum Point Associates,	Plum Point Energy	Mississippi, Ar	8/20/2003	Auxillary Boiler	175 M

: C-1
[OUSE (RBLC) SO_2 CONTROL TECHNOLOGIES

ity	Control Description	Emission Limit1	Case-By-Case Basis	Emission Limit2	Standard Emission Limit
		93 lb/H			
	Dry Flue Gas Desulfurization & Low Sulfur Coal. Emission Limit Basis - 30-Day Avg.	0.12 lb/MMBtu	Other Case-By-Case		0.12 lb/MMBtu
	Kcpl Shall Install Scr Unit For The Unit 2 Boiler To Reduce Nox Emissions And Also Shall Install Wet Scrubber To Reduce Sox Emissions. Both Controls Are Not Bact For Nox And Sox	0.09 lb/MMBtu	Bact-Psd	4374 lb/H	6885 lb/H
		2.84 lb/H	Bat (Non-Us Only)	0.33 T/Yr	0.5 % By Weight
		0.15 lb/H	Bat (Non-Us Only)	0.33 T/Yr	0.6 lb/Mmscf
	Spray Dryer Adsorber Or Dry Sodium Bicarbonate Injection System	22.13 lb/H	Bat (Non-Us Only)	96.93 T/Yr	0.087 lb/MMBtu
		237 lb/H	Other Case-By-Case		0.23 lb/MMBtu
)	Emission Restriction, Limestone Injection Plus A Dry Polishing Scrubber, Emission Monitored By Cem Which Is Basis For Efficiency Control	0.156 lb/MMBtu	Bact-Psd	0.234 Lbs/MMBtu	
		0.203 lb/MMBtu	Other Case-By-Case	11.08 T/Yr	0.203 lb/MMBtu
	Dry Flue Gas Desulfurization Sysytem	0.274 lb/MMBtu	Bact-Psd	0.2 Lbs/MMBtu	0.274 lb/MMBtu
		0.11 lb/Hr			
		3585 Tpy			
		2456 lb/H		982 lb/Hr	
		510 lb/Hr		2027 Tpy	
	Thermal Oxiders And Cem System	3.9 lb/H		15.9 T/Yr	
	Thermal Oxidizers And Cem System	2.2 lb/H		8.9 T/Yr	
		0.025 lb/Mmbty	Bact-Psd	47.1 T/Yr	0.025 lb/MMBtu
	Proper Design And Operation. Wood Ash Alkalinity Acts As The Scrubbing Media. Use Of Transportation Grade Fuel Oil.	355.7 lb/H	Bact-Psd	577.9 T/Yr	0
;	Proper Design And Operaton	100 Ppmdv @ 8% O2	Bact-Psd	222.1 lb/H	0
;	Wet Scrubber And Low Sulfide Water	0.05 lb/T Bls	Bact-Psd	4.1 lb/H	0
		0.1 lb/MMBtu	Bact-Psd	62 lb/H	0.1 lb/MMBtu
	Low Sulfur Fuel Oil	2.3 T/Yr	Bact-Psd		0.051 lb/MMBtu

TA
SUMMARY OF RACT/BACT/LAER CLEAR

Rblc Id No.	Corporate or Company Name	Facility Name	Location	Permit Date	Process Name	Unit
	Llc					
Ar-0074	Plum Point Associates, Llc	Plum Point Energy	Mississippi, Ar	8/20/2003	Boiler , Unit 1 - Sn-01	800 Mw
Ar-0079	Plum Point Associates, Llc	Plum Point Energy	Mississippi, Ar	8/20/2003	Auxiliary Boiler	175 MM
Ar-0079	Plum Point Associates, Llc	Plum Point Energy	Mississippi, Ar	8/20/2003	Boiler - Sn-01	800 Mw
Co-0055	Lamar Utilities Board Dba Lamar Light & Power	Lamar Light & Power Power Plant	Powers, Co	2/3/2006	Circulating Fluidized Bed Boiler	501.7 M
Co-0055	Lamar Utilities Board Dba Lamar Light & Power	Lamar Light & Power Power Plant	Powers, Co	2/3/2006	Diesel Engines For Switching, Locomotive & Fire Pump	1500 Hp
Fl-0034	U.S. Sugar Corp.	U.S. Sugar Clewiston Mill And Refinery	Hendry, Fl	11/29/2000	Boiler, Traveling Grate	633 MM
Fl-0178	Jea Northside Generating Station	Jea Northside Generating Station	Duval, Fl	7/14/1999	Boiler, Coal	2764 MI
Fl-0248	Us Sugar Corporation	Us Sugar Corporation	Hendry, Fl	11/19/1999	Boiler, Bagasse, No. 4	633 MM
Fl-0257	U.S. Sugar Corporation	Clewiston Sugar Mill And Refinery	Hendry, Fl	11/18/2003	External Combustion, Multiple Fuels	936 MM
Ia-0046	Archer Daniels Midland Company	Archer Daniels Midland Company	Linn, Ia	6/30/1998	Boiler, Coal Fired, Cfb, Atmospheric, #6	1500 MI
Ia-0046	Archer Daniels Midland Company	Archer Daniels Midland Company	Linn, Ia	6/30/1998	Boiler, Coal Fired, Circul. Fluidized Bed, #5	1500 MI
Ia-0051	Archer Daniels Midland Company	Archer Daniels Midland Company	Linn, Ia	6/30/1998	Boiler, Circulating Fluidized Bed, Coal Fired	1500 MI
Ia-0067	Midamerican Energy Company	Midamerican Energy Company	Pottawattamie, Ia	6/17/2003	Auxiliary Boiler	429.4 M
Ia-0067	Midamerican Energy Company	Midamerican Energy Company	Pottawattamie, Ia	6/17/2003	Cbec 4 Boiler & 3 Carbon Silos	7675 MI
Ia-0067	Midamerican Energy Company	Midamerican Energy Company	Pottawattamie, Ia	6/17/2003	Diesel Fire Pump	27.8 Ga
Ia-0067	Midamerican Energy Company	Midamerican Energy Company	Pottawattamie, Ia	6/17/2003	Emergency Generator	97.73 G
Il-0060	Archer Daniels Midland Company	Archer Daniels Midland Company	Macon, Il	12/24/1998	Boiler (9&10), Fluidized Bed	1500 M
Ks-0026	Sand Sage Power, Llc	Holcomb Unit #2	Finney, Ks	10/8/2002	Boiler, Pulverized Coal	660 Mw
Ky-0079	Kentucky Mountain Power, Llc	Kentucky Mountain Power, Llc	Knott, Ky	5/4/2001	Boiler, Circulating Fluidized Bed Units 1 & 2	2550 M
Ky-0084	Thoroughbred Generating Company, Llc	Thoroughbred Generating Station	Muhlenberg, Ky	10/11/2002	Boiler, Auxiliary, Diesel	300 MM
Ky-0084	Thoroughbred Generating Company, Llc	Thoroughbred Generating Station	Muhlenberg, Ky	10/11/2002	Boiler, Coal, (2)	7446 M
Ky-0085	Meadwestvaco Kentucky, Inc	Meadwestvaco Kentucky, Inc/Wickliffe	Ballard, Ky	2/27/2002	Boiler, Bark	631 MM
Ky-0085	Meadwestvaco	Meadwestvaco	Ballard, Ky	2/27/2002	Recovery Furnace	473000

C-1
OUSE (RBLC) SO_2 CONTROL TECHNOLOGIES

ity	Control Description	Emission Limit1	Case-By-Case Basis	Emission Limit2	Standard Emission Limit
	Dry Flue Gas Desulfurization	0.16 lb/MMBtu	Bact-Psd		0.16 lb/MMBtu
	Low Sulfur Fuel Oil. Sulfur Content < 0.05% S By Wt.	2.3 T/Yr	Bact-Psd		0.051 lb/MMBtu
	Dry Flue Gas Desulfurization	0.16 lb/MMBtu	Bact-Psd		0.16 lb/MMBtu
l	Limestone Injection For S02 Control . Sand Is Used As Inert Material For Regulation Of Circulating Bed Temperature	0.103 lb/MMBtu	Bact-Psd		
	Low Sulfur Fuel. Less Tan 0.05 By Wheight	0.06 lb/MMBtu	Bact-Psd		
	Low Sulfur No. 6 Fuel Oil (0.70% Sulfur)	0.06 lb/MMBtu	Bact-Psd		0.06 lb/MMBtu
l	Proposed Controls: Circ. Fluidized Bed Scrubber/Electrostatic Prec. Or Spray Dryer Absorber/Fabric Filter Or Circ. Fluidized Bed Scrubber/Fabric Filter.	0.2 lb/MMBtu	Bact-Psd	0.15 lb/MMBtu	0.2 lb/MMBtu
	Low Sulfur Fuels Fuel Oil < 0.7 % S By Wt	0.06 lb/MMBtu	Bact-Psd		0.06 lb/MMBtu
	Fuel Specifications: Bagass And Distillate Oil (< 0.05% S By Wt)	0.06 lb/MMBtu	Bact-Psd		0.06 lb/MMBtu
l	Limestone Injection In Circulating Fluidized Bed (Cfb).	0.36 lb/MMBtu 30 D Rollin	Bact-Psd	0	0
l	Limestone Injection In Circulating Fluidized Bed.	0.36 lb/MMBtu 30 D Rollin	Bact-Psd	0	0
l	Limestone Injection In Cfb.	0.36 lb/MMBtu 30 D Rollin	Bact-Psd	674.88 lb/H (1 H)	0.36 lb/MMBtu
lr	Good Combustion Practices	0.0006 lb/MMBtu	Bact-Psd		0.0006 lb/MMBtu
lr	Lime Spray Dryer Flue Gas Desulfurization	0.1 lb/MMBtu	Bact-Psd	3362 Tons/Yr	0.1 lb/MMBtu
	Good Combustion Practices And Low Sulfur Fuel	0.052 lb/MMBtu	Bact-Psd	0.05 Tons/Yr	
	Good Combustion Practices And Low Sulfur Fuel	0.052 lb/MMBtu	Bact-Psd	0.17 Tons/Yr	
l	Limestone Injection Into Fluidized Bed, Followed By Fabric Filter Pm Control.	0.7 lb/MMBtu	Bact-Psd	0	0.7 lb/MMBtu
	Dry Flue Gas Desulfurization	0.12 lb/MMBtu	Other Case-By-Case		0.12 lb/MMBtu
l	Nids - Natural Integrated Desulfurization System	0.13 lb/MMBtu	Other Case-By-Case		0.13 lb/MMBtu
	Good Operating Practice, Limit On Operating Hours	0.05 lb/MMBtu	Bact-Psd		0.05 lb/MMBtu
l	Wet Flue Gas Desulfurization (Fgd), Wesp, And Proper Boiler Design	0.167 lb/MMBtu	Bact-Psd	0.41 lb/MMBtu	0.167 lb/MMBtu
		0.8 MMBtu/H	Bact-Psd		0.8 MMBtu/H
	Wet Scrubber	0.29 lb/T Adp	Bact-Psd		

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SUMMARY OF RACT/BACT/LAER CLEARI[illegible]

Rblc Id No.	Corporate or Company Name	Facility Name	Location	Permit Date	Process Name	Unit C
	Kentucky, Inc	Kentucky, Inc/Wickliffe				
Ky-0086	East Kentucky Power Coop., Inc.	East Kentucky Power Coop., Inc./Spurlock Power Sta	Mason. Ky	8/4/2002	Boiler, Cfb, Coal	2500 MM
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Administration Building Diesel Generator	587 Hp
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Auxiliary Diesel Generators No.1 & No.2	1100 Hp
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Caterpillar Back-Up Diesel Air Compressors, 2	775 Hp E
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Clarifier Diesel Engine	310 Hp
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Detroit Diesel Fire-Water Pump 2 & 3	265 Hp E
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Effluent Lift Pit Diesel Engine	152 Hp
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Lime Kiln	142 MME
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Lime Kiln Auxiliary Engine	370 Hp
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Mud Storage Diesel Generator	130 Hp
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Ncg Incinerator	6.5 MMB
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Power Boiler #1 & #2, Coal	645 MME
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Power Boiler #1 & #2, Combined Fuel	760 MME
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Power Boiler #1 & #2, Oil	645 MME
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Recovery Boiler No.1 And No.2	71 Tbls/H
La-0122	International Paper - Mansfield Mill	Mansfield Mill	De Soto Parish, La	8/14/2001	Waste Clarifier Diesel Engine	413 Hp
La-0176	Louisiana Generating, Llc	Big Cajun Ii Power Plant	Pointe Coupee, La	8/22/2005	New 675 Mw Pulverized Coal Boiler (Unit 4)	3518791
La-0188	Inland Paperboard And Packaging (Gaylord)	Bogalusa Mill	Washington, La	11/23/2004	No. 12 Hogged Fuel Boiler	787.5 MM
Me-0021	S.D. Warren Co. - Skowhegan, Me	S.D. Warren Co. - Skowhegan, Me	Somerset, Me	11/27/2001	Boiler, #2	1300 MM
Me-0026	Wheelabrator Sherman Energy Company	Wheelabrator Sherman Energy Company	Penobscot, Me	4/9/1999	Boiler # 1	315 MME
Mn-0057	Powerminn 9090 Llc	Fibrominn Biomass Power Plant	Swift, Mn	10/23/2002	Boiler, Multifuel	792 MME
Ms-0036	Choctaw Generation Limited, Partnership	Choctaw Generation Limited, Partnership	Choctaw, Ms	8/25/1998	Boilers, Circulating Fluidized Bed	2475.6 M Each
Mt-0022	Bull Mountain Dev. Company	Bull Mountain, No. 1, Llc - Roundup Power Project	Musselshell, Mt	7/21/2003	Boiler, Auxiliary, # 1 & #2	117 MME

C-1
OUSE (RBLC) SO_2 CONTROL TECHNOLOGIES

ity	Control Description	Emission Limit1	Case-By-Case Basis	Emission Limit2	Standard Emission Limit
	Limestone Injection And Dry Lime Scrubber	0.2 lb/MMBtu	Bact-Psd		0.2 lb/MMBtu
	Preventative Maintenance	1.2 lb/H	Bact-Psd	0.8 T/Yr	
	Preventative Maintenance	2.2 lb/H	Bact-Psd	1.6 T/Yr	
	Preventative Maintenance	1.6 lb/H	Bact-Psd	1.4 T/Yr	
	Preventative Maintenance	0.63 lb/H	Bact-Psd	0.8 T/Yr	
	Preventative Maintenance	0.54 lb/H	Bact-Psd	0.4 T/Yr	
	Preventative Maintenance	0.31 lb/H	Bact-Psd	0.2 T/Yr	
	Cao And Wet Scrubber Using Caustic Solution	8.4 lb/H	Bact-Psd	29.3 T/Yr	
	Preventative Maintenance	0.22 lb/H	Bact-Psd	0.2 T/Yr	
	Preventative Maintenance	0.26 lb/H	Bact-Psd	0.2 T/Yr	
		48.7 lb/H	Bact-Psd	213.3 T/Yr	
	Sulfur In Coal Not To Exceed 1.2% By Weight	774 lb/H	Bact-Psd		1.2 lb/MMBtu
	Limit Sulfur Content Of Fuel		Bact-Psd		
	Sulfur Content Of Fuel Shall Not Exceed 0.7% By Weight.	516 lb/H	Bact-Psd		0.8 lb/MMBtu
	Good Process Controls	510 lb/H	Bact-Psd	2233.8 T/Yr	
	Preventative Maintenance	0.84 lb/H	Bact-Psd	0.6 T/Yr	
	Option 1: Semi-Dry Lime Scrubber Option 2: Wet Flue Gas Desulfurization System	656.6 lb/H	Bact-Psd	2875.9 T/Yr	0.1 lb/MMBtu
	Limit Annual Fuel Oil Capacity Factor To <=10%.	1209.75 lb/H	Bact-Psd	842.97 T/Yr	1.54 lb/MMBtu
	Sodium Based Wet Scrubber	351 lb/H	Bact-Psd	1537 T/Yr	0.27 lb/MMBtu
	Firing Of Wood Only, Oil Only During Startup, Flame Stablization, Or As Emerg.Backup. Oil S < 0.5% By Wt.	38.9 lb/H	Bact-Psd	170.3 T/Yr	0.12 lb/MMBtu
	Spray Dryer/Absorber	0.07 lb/MMBtu	Bact-Psd		0.07 lb/MMBtu
	Circulating Fluidized Bed With Lime Injection.	0.25 lb/MMBtu	Bact-Psd	0	0.25 lb/MMBtu
	Use Of Low Sulfur Fuel Oil (0.05% S), Limit On Hours Of Operation.	6.47 lb/H	Bact-Psd		0.055 lb/MMBtu

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SUMMARY OF RACT/BACT/LAER CLEARI

Rblc Id No.	Corporate or Company Name	Facility Name	Location	Permit Date	Process Name	Unit
Mt-0022	Bull Mountain Dev. Company	Bull Mountain, No. 1, Llc - Roundup Power Project	Musselshell, Mt	7/21/2003	Boiler, Pc No. 1	390 Mw
Mt-0022	Bull Mountain Dev. Company	Bull Mountain, No. 1, Llc - Roundup Power Project	Musselshell, Mt	7/21/2003	Boiler, Pc No. 2	390 Mw
Mt-0022	Bull Mountain Dev. Company	Bull Mountain, No. 1, Llc - Roundup Power Project	Musselshell, Mt	7/21/2003	Ic Engine, Emergency Generator	15.3 MN
Mt-0027	Rocky Mountain Power, Inc.	Hardin Generator Project	Big Horn, Mt	6/11/2002	Boiler, Pulverized Coal-Fired	1304 MI
Nc-0070	Weyerhaeuser Company	Weyerhaeuser - Plymouth Pulp And Paper Mill	Martin, Nc	11/25/1998	Boiler, No. 1 Hog Fuel	835 MM
Nc-0070	Weyerhaeuser Company	Weyerhaeuser - Plymouth Pulp And Paper Mill	Martin, Nc	11/25/1998	Boiler, No. 2 Hog Fuel	889 MMI
Nd-0018	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Ransom, Nd	7/9/1998	Boiler, Jta	280 MMI
Nd-0018	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Ransom, Nd	7/9/1998	Boiler, Kewaunee	13 MMBt
Nd-0018	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Ransom, Nd	7/9/1998	Boiler, Trane Murray, Backup Oil	189 MME
Nd-0018	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Ransom, Nd	7/9/1998	Boiler, Trane Murray, Nat Gas	189 MME
Nd-0018	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Ransom, Nd	7/9/1998	Boilers, 2 , Wellons	200 MMB
Nd-0018	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Archer Daniels Midland Co. - Northern Sun Veg. Oil	Ransom, Nd	7/9/1998	Generator, Backup Diesel	25 Kw
Nd-0021	Montana Dakota Utilities / Westmoreland Power	Gascoyne Generating Station	Bowman, Nd	6/3/2005	Boiler, Coal-Fired	2116 MMI
Nd-0022	Archer Daniels Midland Company	Northern Sun	Ransom, Nd	5/1/2006	Wood/Hull Fired Boiler	
Ne-0018	Hastings Utilities	Whelan Energy Center	Adams, Ne	3/30/2004	Boiler, Unit 2 Utility	2210 MME
Ne-0031	Omaha Public Power District	Oppd - Nebraska City Station	Otoe, Ne	3/9/2005	Unit 2 Boiler	
Nh-0013	Public Service Of New Hampshire	Schiller Station	Rockingham, Nh	10/25/2004	Boiler, Coal Fired, Unit #5	635 MMBt
Nh-0013	Public Service Of New Hampshire	Schiller Station	Rockingham, Nh	10/25/2004	Boiler, Coal Fired, Unit #5	635 MMBt
Nv-0036	Newmont Nevada Energy Investment, Llc	Ts Power Plant	Eureka, Nv	5/5/2005	200 Mw Pc Coal Boiler	2030 MME

C-1
OUSE (RBLC) SO_2 CONTROL TECHNOLOGIES

:y	Control Description	Emission Limit1	Case-By-Case Basis	Emission Limit2	Standard Emission Limit
	Dry Flue Gas Desulfurization (Fgd)	481.6 lb/H	Bact-Psd	0.12 lb/MMBtu	0.12 lb/MMBtu
	Dry Flue Gas Desulfurization (Fgd)	481.6 lb/H	Bact-Psd	0.12 lb/MMBtu	0.12 lb/MMBtu
	Low Sulfur #2 Fuel Oil (0.05% S), Limited To 200 H Of Operation Per Year	97.7 % Reduction	Bact-Psd		
	Wet Venturi Scrubber	0.14 lb/MMBtu	Other Case-By-Case		0.14 lb/MMBtu
	Wet Scrubber	0.8 lb/MMBtu	Other Case-By-Case	1.2 lb/MMBtu	0.8 lb/MMBtu
	Wet Scrubber	0.8 lb/MMBtu	Other Case-By-Case	1.2 lb/MMBtu	0.8 lb/MMBtu
		0.002 lb/MMBtu	Bact-Psd		0.002 lb/MMBtu
		4 lb/H	Bact-Psd		0.31 lb/MMBtu
	Low Sulfur Fuel	0.2 lb/MMBtu	Bact-Psd	0.2 Wt % Sulfur In Oil	0.2 lb/MMBtu
	Natural Gas	0.2 lb/MMBtu	Bact-Psd		0.2 lb/MMBtu
		0.002 lb/MMBtu	Bact-Psd		0.002 lb/MMBtu
		0.1 lb/H	Bact-Psd		1.37 G/Bhp-H
	Limestone Injection With A Spray Dryer.	0.038 lb/MMBtu	Bact-Psd	140 lb/H	0.038 lb/MMBtu
		0.47 lb/Mm Btu	Bact-Psd		
	Spray Dryer Absorber (Sda)	0.12 lb/MMBtu	Bact-Psd	1.1 lb/MMBtu	0.12 lb/MMBtu
	Dry Flue Gas Desulfurization & Fabric Filter	0.095 lb/MMBtu	Bact-Psd	0.163 lb/MMBtu	0.48 lb/MMBtu
	Lime Injection, Fuel Sulfur Limits	0.12 lb/MMBtu	Other Case-By-Case		0.12 lb/MMBtu
	Lime Injection, Fuel Sulfur Limits	0.12 lb/MMBtu	Other Case-By-Case		0.12 lb/MMBtu
	Lime Spray Spray Dry Scrubber	0.09 lb/MMBtu	Bact-Psd	95 Percent	

WESTON SOLUTIONS

TAE

SUMMARY OF RACT/BACT/LAER CLEARIN

Rblc Id No.	Corporate or Company Name	Facility Name	Location	Permit Date	Process Name	Unit C
Nv-0036	Newmont Nevada Energy Investment, Llc	Ts Power Plant	Eureka, Nv	5/5/2005	35 Mw Combustion Turbines	373.3 MM
Oh-0231	First Energy	Toledo Edison Co. - Bayshore Plant	Lucas, Oh	7/31/2003	Boiler, Cfb, Coke/Coal-Fired	1764 MM
Oh-0231	First Energy	Toledo Edison Co. - Bayshore Plant	Lucas, Oh	7/31/2003	Limestone Dryer	87 Gal/H Oil
Pa-0162		Edison Mission Energy	Indiana, Pa	5/25/1999	Boiler, Coal, Pulverized Bituminous, Unit 3	6600 MM
Pa-0182	Reliant Energy	Reliant Energy Seward Power	Indiana, Pa	8/26/2003	Boiler, Circulating Fluidized Bed, (2)	2532 MM
Pr-0007	Aes Puerto Rico	Cogeneration Plant (Aes-Prcp)	Guayama, Pr	10/29/2001	2 Coal-Fired Circulating Fluidized Bed Boilers	454 Mw (
Pr-0007	Aes Puerto Rico	Cogeneration Plant (Aes-Prcp)	Guayama, Pr	10/29/2001	Emergency Boiler Feed Pump- Diesel Engine	
Pr-0007	Aes Puerto Rico	Cogeneration Plant (Aes-Prcp)	Guayama, Pr	10/29/2001	Limestone Dryer	13 MMBt
Sc-0104	Santee Cooper	Santee Cooper Cross Generating Station	Berkeley, Sc	2/5/2004	Boiler, No. 3 And No. 4	5700 MM
Tx-0275	Reliant Energy, Inc.	W.A. Parish Electric Generating Station	Fort Bend, Tx	12/21/2000	Utility Boiler Unit 8	6700 MM
Tx-0298	Reliant Energy Inc	Wa Parish Electric Generating Station	Fort Bend, Tx	10/15/2003	(2) Boilers, Units 5 & 6, Coal & Gas, Wap5&6	7400 MM
Tx-0298	Reliant Energy Inc	Wa Parish Electric Generating Station	Fort Bend, Tx	10/15/2003	(2) Boilers, Units 5 & 6, Wap5&6, Coal	7400 MM
Tx-0298	Reliant Energy Inc	Wa Parish Electric Generating Station	Fort Bend, Tx	10/15/2003	Boiler Unit 7, Coal & Gas, Wap7	6700 MM
Tx-0298	Reliant Energy Inc	Wa Parish Electric Generating Station	Fort Bend, Tx	10/15/2003	Boiler Unit 7, Coal, Wap7	6700 MM
Tx-0342	Reliant Energy Inc	Limestone Electric Generating Station	Limestone, Tx	5/23/2001	(2) Boiler Unit 1 & 2 Scrubber Stacks, Lms1 & 2	7863 MM
Tx-0358	Reliant Energy, Inc	Washington Parish Electric Generating Station	Fort Bend, Tx	10/15/2002	(2) Boiler Stacks, Wap 5 & 6 , Coal & Nat Gas	7400 MM
Tx-0358	Reliant Energy, Inc	Washington Parish Electric Generating Station	Fort Bend, Tx	10/15/2002	(2) Boiler Stacks, Wap 5 & 6 , Coal Only	6750 MM
Tx-0358	Reliant Energy, Inc	Washington Parish Electric Generating Station	Fort Bend, Tx	10/15/2002	Boiler Stack, Wap 7, Coal & Nat Gas	6700 MM
Tx-0358	Reliant Energy, Inc	Washington Parish Electric Generating Station	Fort Bend, Tx	10/15/2002	Boiler Stack, Wap 7, Coal Only	6700 MM
Ut-0053	Deseret Generation And Transmission Company	Deseret Generation And Transmission Company	Uintah, Ut	3/16/1998	Coal Fired Boiler	500 Mw
Ut-0053	Deseret Generation And Transmission Company	Deseret Generation And Transmission Company	Uintah, Ut	3/16/1998	Conveyor Coal	475 T/H
Ut-0064	Nevco - Sevier Power Company	Sevier Power Company	Sevier, Ut	10/12/2004	Cfb Boiler With Dry Lime Scrubber	270 Mw

C-1

USE (RBLC) SO_2 CONTROL TECHNOLOGIES

y	Control Description	Emission Limit1	Case-By-Case Basis	Emission Limit2	Standard Emission Limit
	Low Sulfur Fuel, <0.5%W	0.05 %W	Bact-Psd		
	Limestone Fluidized Bed	1897.6 lb/H	N/A	5541 T/Yr	0.73 lb/MMBtu
l	Number 2 Fuel Oil Not To Exceed 0.39% Sulfur, And And All Fuel Oil Tested	4.83 lb/H		21.15 T/Yr	
	Wet Limestone Scrubber	0.4 lb/MMBtu	Other Case-By-Case	12720 T/Yr	0.4 lb/MMBtu
	Fly Ash Reinjection	0.6 lb/MMBtu	Other Case-By-Case		0.6 lb/MMBtu
	Low-Sulfur Coal (Max 1% S) And Distillate Oil (Max 0.05% S)And A Limestone Injection System And Circulating Dry Scrubber	9 Ppmvd @ 7% O2	Bact-Psd	54.1 lb/H	0.022 lb/MMBtu
	Limited Operation And Limited Fuel Sulfur Content	0.82 lb/H	Bact-Psd		
	Using Propane And Low Sulfur Distillate Oil And Direct Contact With Limestone	0.26 lb/H	Bact-Psd		0.02 lb/MMBtu
	Flue Gas Desulfurization (Wet Scrubbing)	0.13 lb/MMBtu	Other Case-By-Case	3250 T/Yr	0.13 lb/MMBtu
	Flue Gas Desulurization	2063 lb/H	Other Case-By-Case	4081 T/Yr	0.3 lb/MMBtu
	Fuel S Content Limited	7884 lb/H	N/A	34530 T/Yr	1.2 lb/MMBtu
	Fuel S Content Limited	7884 lb/H	N/A	34530 T/Yr	1.06
	Fuel S Content Limited	6875 lb/H	N/A	30112 T/Yr	1.2 lb/MMBtu
	Limited Fuel S Content	6875 lb/H	N/A	30112 T/Yr	1.2 lb/MMBtu
Ea	Wet Limestone Flue Gas Desulfurization	9000 lb/H	N/A	6479 lb/H	0.82 lb/MMBtu
	Burn Low-S Subbituminous Coal	7884 lb/H	N/A	34530 T/Yr	1.065 lb/MMBtu
	None Indicated	7884 lb/H	N/A	34530 T/Yr	1.2 lb/MMBtu
	Burn Low-S Subbituminous Coal	6875 lb/H	N/A	30112 T/Yr	1.2 lb/MMBtu
	Burn Low-S Subbituminous Coal	6875 lb/H	N/A	30112 T/Yr	1.2 lb/MMBtu
	Wet Scrubber	0.0976 lb/MMBtu 12 Mo. Avg.	Bact-Psd	0.15 lb/MMBtu 30 Day Avg.	0
		1968.11 T/Y	Bact-Psd	0	0
	Low Sulfur Coal And Dry Lime Scrubber	0.05 lb/MMBtu	Bact-Psd	0.022 lb/MMBtu	0.05 lb/MMBtu

WESTON SOLUTIONS

TAB
SUMMARY OF RACT/BACT/LAER CLEARIN

Rblc Id No.	Corporate or Company Name	Facility Name	Location	Permit Date	Process Name	Unit Ca
Ut-0065	Intermountain Power Service Corporation	Intermountain Power Generating Station - Unit #3	Millard, Ut	10/15/2004	Pulverized Coal Fired Electric Generating Unit	950 Mw-G
Va-0268	Martinsville Thermal, Llc	Thermal Ventures	Henry, Va	2/15/2002	Boiler, Steam	120 MMBt
Va-0268	Martinsville Thermal, Llc	Thermal Ventures	Henry, Va	2/15/2002	Boiler, Steam	120 MMBt
Va-0296	Virginia Polytechnic Institute And State Universit	Virginia Tech	Montgomery County, Va	9/15/2005	Operation Of Boiler 11	146.7 MM
Wi-0225	Manitowoc Public Utilities	Manitowoc Public Utilities	Manitowoc, Wi	12/3/2003	Circulating Fluidized Bed Boiler (Electric Generation)	650 MMBt
Wi-0228	Wisconsin Public Service	Wps - WESTON Plant	Marathon,. Wi	10/19/2004	Auxilliary Nat. Gas Fired Boiler (B25, S25)	229.8 MM
Wi-0228	Wisconsin Public Service	Wps - Weston Plant	Marathon, Wi	10/19/2004	B63, S63; B64, S64 - Natural Gas Station Heater 1 And 2	0.75 MMB
Wi-0228	Wisconsin Public Service	Wps - WESTON Plant	Marathon, Wi	10/19/2004	Diesel Booster Pump (B27, S27)	265 Hp
Wi-0228	Wisconsin Public Service	Wps - WESTON Plant	Marathon, Wi	10/19/2004	Main Fire Pump (Diesel Engine)	460 Hp
Wi-0228	Wisconsin Public Service	Wps - WESTON Plant	Marathon, Wi	10/19/2004	Super Critical Pulverized Coal Electric Steam Boiler (S04, P04)	5173.07 M
Wv-0023	Longview Power, Llc	Maidsville	Monongahela, Wv	3/2/2004	Auxiliary Boiler	225 MMBt
Wv-0023	Longview Power, Llc	Maidsville	Monongahela, Wv	3/2/2004	Boiler, Pc	6114 MME
Wv-0023	Longview Power, Llc	Maidsville	Monongahela, Wv	3/2/2004	Emergency Generator	1801 Hp
Wv-0023	Longview Power, Llc	Maidsville	Monongahela, Wv	3/2/2004	Ic Engine, Fire Water Pump	85 Hp
Wv-0024	Western Greenbrier Co-Generation, Llc	Western Greenbrier Co-Generation, Llc	Greenbrier, Wv	4/26/2006	Cementitious Material Kiln	13 MMBtu
Wv-0024	Western Greenbrier Co-Generation, Llc	Western Greenbrier Co-Generation, Llc	Greenbrier, Wv	4/26/2006	Circulating Fluidized Bed Boiler (Cfb)	1070 MME
Wy-0039	Two Elk Generation Partners, Limited Partnership	Two Elk Generation Partners, Limited Partnership	Campbell, Wy	2/27/1998	Boiler, Steam Electric Power Generating	250 Mw
Wy-0047	Encoal Corporation-Encoal North Rochelle Facility	Encoal Corporation-Encoal North Rochelle Facility	Campbell,Wy	10/10/1997	Boiler, Coal Fired, Main Stack	3960 MME
Wy-0047	Encoal Corporation-Encoal North Rochelle Facility	Encoal Corporation-Encoal North Rochelle Facility	Campbell, Wy	10/10/1997	Liquids From Coal Plant (3 Modules Per Plant)	1200 MME

C-1
OUSE (RBLC) SO_2 CONTROL TECHNOLOGIES

ty	Control Description	Emission Limit1	Case-By-Case Basis	Emission Limit2	Standard Emission Limit
	Wet Flue Gas Desulphurization, Low Sulfer Coal	0.1 lb/MMBtu	Bact-Psd	0.09 lb/MMBtu	0.1 lb/MMBtu
	Good Combustion Practices And Continuous Emission Monitoring Device.	0.47 lb/MMBtu	Other Case-By-Case	247 T/Yr	0.47 lb/MMBtu
	Good Combustion Practices, Clean Burning Fuel, And Continuous Emission Monitoring Device.	0.47 lb/MMBtu	Other Case-By-Case	247 T/Yr	0.47 lb/MMBtu
	Dry Scrubber Flue Gas Desulfurization System And Cems	0.161 lb/MMBtu	Bact-Psd	23.6 lb/H	0.161 lb/MMBtu
	Circulating Fluidized Bed Boiler With Lime Injection;	0.3 lb/MMBtu	N/A	71.2 T/Mo	
	Natural Gas	0.0006 lb/MMBtu	Bact-Psd	0.14 lb/H	
	Natural Gas	0.0004 lb/H	Bact-Psd		
	Fuel Sulfur Content Limit (0.003 Wt. % S) Good Combustion Practices	0.54 lb/H	Bact-Psd	0.003 Wt % S	
	Good Combustion Practices, Ultra Low Sulfur (0.003 Wt. % S) Diesel Fuel Oil	0.94 lb/H	Bact-Psd	0.003 Wt % S	
/H	Dry Fgd, Limit On Emissions Entering Control System: 1.23 Lbs/MMBtu 30 Day Avg.	0.1 lb/MMBtu	Bact-Psd	0.09 lb/MMBtu	
	Low Sulfur Natural Gas Fuel	0.004 lb/H	Bact-Psd		1.8 E-5 lb/MMBtu
	Wet Limestone Forced Oxidation	917 lb/H	Bact-Psd	0.12 lb/MMBtu	0.15 lb/MMBtu
	Sulfur Content In The Fuel Limited To 0.05% By Weight	6.5 lb/H	Bact-Psd	1.6 T/Yr	
	Sulfur Content Limited To 0.05% By Weight	3.3 lb/H	Bact-Psd	0.825 T/Yr	
	Conditioning Tower	0.6 lb/T	Bact-Psd		0.6 lb/T
	Lime Injection And Flash Dryer Absorber (Fda)	0.14 lb/MMBtu	Bact-Psd	0.14 lb/MMBtu	0.14 lb/MMBtu
	Lime Spray Dry Scrubber	0.2 lb/MMBtu (2hr Fixed)	Bact-Psd	0.17 lb/MMBtu (30d Roll)	0.2 lb/MMBtu
	Lime Spray Dryer	0.2 lb/MMBtu (2 H Fixed)	Bact-Psd	0	0
	Lime Spray Dryer	240 lb/H (2hr Fixed)	Bact-Psd	0	0